BEFORE THE ARIZONA CORPORATION COMMISSION

MARC SPITZER
Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner

IN THE MATTER OF THE APPLICATION OF	)	DOCKET NO. E-01345A-03-0437
ARIZONA PUBLIC SERVICE COMPANY FOR	)	
A HEARING TO DETERMINE THE FAIR VALUE	)	
OF THE UTILITY PROPERTY OF THE COMPANY	)	
FOR RATEMAKING PURPOSES, TO FIX A JUST	)	
AND REASONABLE RATE OF RETURN THEREON	)	
TO APPROVE RATE SCHEDULES DESIGNED TO	)	
DEVELOP SUCH RETURN, AND FOR APPROVAL	)	
OF PURCHASED POWER CONTRACT	)	

DIRECT TESTIMONY

OF

LEE SMITH

ON BEHALF OF THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 3, 2004

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I. INTRODUCTION

Q. What is your name and business address?

A. My name is Lee Smith, and I work for La Capra Associates, 20Winthrop Square, Boston, Massachusetts.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Arizona Corporation Commission (Commission) Staff.

Q. Please describe your background and experience.

A. I am a Senior Economist at La Capra Associates. I have been with this energy planning and regulatory economics firm for 20 years. Prior to my employment at La Capra Associates, I was Director of Rates and Research, in charge of gas, electric, and water rates, at the Massachusetts Department of Public Utilities. Prior to that period, I taught economics at the college level. My resume is attached as Exhibit LS-1. I have testified previously regarding the 1999 Settlement that has given rise to some issues in this proceeding.

Q. What is the purpose of your testimony?

A. I am testifying on several topics. First, I present testimony on the appropriateness of the Company's request for a reversal of its 1999 writeoff of $183 million (after tax) subsequent to the Settlement of 1999. (The pretax value related to the $183 million is $234 million.) I also address the Company's proposed Competition Rules Compliance Charge ("CRCC"), and its request to collect 100% of its divestiture costs. I address some cost allocation issues which are necessary for Mr. Dittmer to complete Staff's overall revenue adjustments, including the cost of transmission. Finally, I comment on the Company's allocated cost of service study and present an allocated, unbundled cost study based on Staff's case.

Q. What is the Company's request regarding the $234 million?

A. The Company is requesting a "reversal" of a writeoff of regulatory assets that it took in 1999. To achieve this "reversal", it is proposing to increase rate base by $141.57 million, to be amortized over 15 years. The net impact on rates will be $7.8 million annually. (Robinson p. 40)

Q. Please summarize your testimony.

A. My testimony addresses the original writeoff and its relation to the rate reduction approved in the order that reviewed the settlement, the impact on the Company of the rate reduction itself, and whether the Company has suffered any significant harm as a result of the Commission's Track A Order, which halted its divestiture to PWEC. I also discuss stranded cost, both theoretically and in this context, since a stranded cost computation was the genesis of the original "writeoff" number. I recommend approval of the Company's proposed treatment of transmission costs, and recommend some modifications to the proposed Competition Rules Compliance Charge. I also support an unbundled allocated cost study which reflects Staff's recommendations on revenue requirements.

Q. Please summarize what you have found with regard to the writeoff issue.

A. I have found that:

- The proposed adjustment is not necessary to produce rates that will recover the Company's ongoing costs;
- The Company's going forward revenue requirements have not been reduced by the previous writeoff;
- While the Commission has modified the order that approved the 1999 Settlement, the Company has not suffered significant harm as a result of this modification;
- While APS did reduce rates as a result of the Settlement, some rate reductions would have occurred even without the Settlement;

- It is unreasonable to assume that APS' rates would have remained unchanged absent the settlement agreement;
- The Company will have collected more than the $350 million of "stranded costs" which the Settlement provided an opportunity for it to collect;
- The original stranded cost amount was based on an estimate of $533 million that was too high.

Q. Is this case about stranded costs?

A. No, it is not. In response to LCA 1-9, the company states that the "opportunity to recover $350 million was not affected by the failure of the Commission to permit the promised divestiture…"

Q. Has the Company actually experienced any stranded costs?

A. No, it has not. Since almost no customers have chosen alternative suppliers, the Company has not had excess generation which it had to sell at an amount less than its embedded cost.

Q. Given the foregoing findings, what are your overall conclusions regarding the request to reverse the writeoff?

A. The proposed adjustment does not meet the normal standard by which revenue requests are judged. While the Company appears to be proposing a different standard, I find that this standard also has not been met. My conclusion is that APS' proposal to reverse the writeoff is not justified, and should not be allowed.

II. THE NORMAL RATEMAKING STANDARD

Q. You indicated above that the adjustment does not meet the normal ratemaking standard. What is the normal ratemaking standard that you believe has not been met?

A. The normal basis for a rate request is going-forward revenue requirements. That is, rates are normally designed to recover what is agreed to as the Company's cost of business. The Company's witness, Dr. Ken Gordon, also describes this standard: "the regulatory agency . . . sets rates that provide the utility a reasonable opportunity to recover its just and reasonable costs." (p.12) If the 1999 writeoff had resulted in a reduction to ratebase or some other change that jeopardized the Company's ability in this case to produce rates that would collect its ongoing costs, this request might have met this standard.

Q. Has the Company said that the rates that it is filing in this proceeding will be lower because it took the writeoff?

A. No. The Company's "…net generation plant...was not impacted by the 1999 Settlement Agreement." (LCA 1-11)

Q. If the Company's request for reversal of the writeoff is granted, will the resulting rates recover more than the Company's ongoing costs?

A. Yes. All else being equal, the proforma adjustment for the amortization of the writeoff will result in rates being set above the Company's current costs.

III. COMPANY PROPOSAL REGARDING THIS ADJUSTMENT

Q. If the request does not meet the normal ratemaking standard, how does the Company justify its request?

A. The Company's position is that as part of the 1999 Settlement it agreed to a number of conditions, in particular to a series of rate reductions, and in return it expected to transfer APS generation assets to PWEC. Since the findings of Track A prevented it from transferring these assets, it apparently believes that it has not received a benefit that it expected, and, as a result, has suffered harm. Mr. Wheeler describes the modification of the order approving the Settlement (elimination of divestiture) as being a case of "detrimental reliance." (Wheeler p.4)

The essence of the Company's claim seems to be that:

(i) APS was entitled to recover $533 million in stranded costs, but in the Settlement it agreed to the collection of $350 million (both in net present value terms);

(ii) APS had planned to establish PWEC and divest its generating facilities to it only because the Commission had previously required divestiture;

(iii) APS had been willing to accept a pretax $234 million write off related to stranded costs (resulting from the aforementioned net present value of $183 million after-tax, the difference between $533 million and $350 million) as the price for being allowed to implement its preferred form of divestiture;

(iv) But for the Commission-mandated divestiture, APS would not have agreed to the write-off as part of the 1999 Settlement;

(v) Given the Commission's reversal of position on divestiture, APS deserves to recover the $234 million write-off.

Q. Has the Company testified that it has not had an opportunity to recover $350 million of stranded cost because the Commission did not permit divestiture?

A. No. In response to LCA1-9, which asked the Company to "…explain whether and how APS' "reasonable opportunity to recovery $350 million…was affected by the non-sale", it says precisely the opposite. "The opportunity to recover $350 million was not affected by the Commission's decision to prevent divestiture of APS generation."

Q. If the Company does not claim that the $234 million is related to an undercollection of stranded costs, what is it actually requesting in the adjustment for $234 million?

A. The Company is essentially making a claim for a retroactive rate adjustment. The Company appears to be saying that 'our rates were lower in the past than we would like, so we would like higher rates in the future.' Although Mr. Wheeler testifies that it is not seeking to take back rate decreases, (Wheeler testimony p. 21), the Company is in fact asking to recover a portion of the rate decreases of the past four years.

The company has made no showing that such revenues are appropriate under normal ratemaking standards, nor has the Company demonstrated that it has been harmed. Furthermore, I describe in Section V how the stranded cost claim by the company that was a basis for the settlement is a dubious figure.

IV. THE COMPANY HAS NOT SUFFERED SIGNIFICANT HARM

Q. Please summarize your response to the Company's claims that it has been harmed.

A. The Company has not established that it has actually suffered significant financial harm. The writeoff has no independent impact, as it did not result in the Company's revenues being reduced, and failure to reverse the writeoff will not result in the Company receiving less than its cost of service in this case. Some rate reductions would have occurred even without the Settlement, and it is unreasonable for APS to assume that its rates would have remained unchanged subsequent to the conclusion of its stranded cost proceeding. The change in policy regarding divestiture has not had a large ongoing impact on the Company's finances. On the other hand, since the Company has been denied the recovery of the one-third of costs associated with restructuring, and with the reversal of Commission policy, it may be appropriate to collect the one-third of costs associated with restructuring in a surcharge mechanism, even though they do not constitute a significant cost.

Q. Did the Company suffer any harm as a result of agreeing to a stranded cost number of $350 million?

A. No. Mr. Wheeler testifies that "the restoration of that write-off has nothing to do with the actual level of stranded costs either incurred by the Company or collected in rates from customers seeking Direct Access. (Testimony, p. 19)[1] I will address the stranded cost situation further in Section V.

Q. Have the Company's revenues since the Settlement been less than they would have been because of the writeoff?

A. No. While revenues have been less than they would have been if no rate reductions had occurred, the writeoff was not the cause of the rate reductions, but the result of the rate reductions. The writeoff, according to the Company, "…was intended to represent a disallowance, on a present value basis, of a portion of the Company's generation-related revenue requirement for the years 1999-2000." (Response to LCA 1-3)

Q. Were the regulatory assets that were the subject of the writeoff included in the assets that formed the basis for the APS stranded cost claim that was addressed in the 1999 Settlement Agreement?

A. No. The regulatory assets that were written down bore no relation to the generating assets that were the subject of the Company's stranded cost claim. LCA 1-5. The Company has indicated that the affected regulatory asset balances had been approved for recovery by the Commission in prior proceedings. (Response to LCA 1-3, Wheeler Direct Testimony at 19.)

Q. What did APS agree to in the Settlement regarding rate decreases?

A. The Settlement specified that APS would reduce rates 1.5% annually for customers of less than 3 MW from 1999 through 2003. Larger customers were

[1] Although as I will explain later, the relevant measure of stranded cost collection is not determined only by customers choosing Direct Access.

also to receive rate decreases. The Settlement also allowed APS to seek a change in rates prior to 2004 in the event of an emergency or of material changes in APS' cost of service resulting from legal or regulatory actions.

Q. APS implies that there would have been no change in its rates if it had not signed this particular Settlement. Do you agree with this?

A. No. The proceeding regarding stranded costs and restructuring that resulted in the Settlement addressed APS' operations and APS' rates. There was a wide divergence of opinions in this proceeding regarding APS' rate levels and its stranded costs, and some parties took positions that may have led to rate reductions. Thus, it is quite possible that if the restructuring case had been litigated rather than settled, APS' rates would have been reduced by Commission order. APS' position that its rates would have remained unchanged if it had not signed this particular Settlement is speculative.

Q. In the absence of the Settlement and the absence of any stranded costs, would a rate decrease have been justified?

A. Yes. Evidence suggests that a rate decrease would have been justified independent of a settlement and/or any stranded costs. Part of the Settlement's initial rate reduction would have been required as a result of the 1996 Rate Reduction Settlement. (See letter from Ms. Klemstine in response to LCA 7-216). Moreover, there is evidence that APS has earned considerably more than its last allowed return on equity for most of the time since the Settlement. Thus, even without the Settlement, APS' rates would have been reduced in 1999, albeit by a lower amount, and also there would have been grounds for reducing APS' rates in the succeeding years. Thus, there is an important question as to what revenues, if any, the Company actually gave up in the Settlement. The Settlement may merely have been the actual mechanism that prevented overearning, but other mechanisms might have also achieved this result.

Q. What is the evidence that APS has overearned?

A. APS files quarterly Financial Reports with the Commission. These show total company returns on equity ("ROE") for calendar years 2000, 2001, and 2002 of 15.2%, 12.4%, and 9.2%. The allowed ROE was 11.75%.

Q. These reports also show a lower return, which reflects the removal of the writedown and the impact of energy trading operations. Does the Company claim that the unadjusted or the adjusted returns reflect its return on equity?

A. The Company argues that the adjusted return should be utilized rather than the total Company ROE. It suggests that earnings from unregulated energy trading operations should not be considered, because they "were not generated by ratepayers revenue". Thus, it has removed either the profits or losses earned by the marketing and trading desk. It also argues that the loss recognized for accounting purposes relative to the "write-down" should not be included. (AECC 1.7) Expenses are increased by an amortization expense associated with the $183 million, which has the effect of reducing net income and reducing the return.

Q. Do you think it is appropriate to adjust the return to remove the effect of energy trading?

A. I do not. The marketing and trading desk was formerly simply a part of APS' operations, but was transferred to PWEC. The energy trading operation, unregulated under PWEC's auspices, has had the ability to generate revenue at least partly because of resources provided by regulated operations. This is particularly true before the first PWEC assets came on line in mid-2001. I note that net income attributed to the unregulated entity significantly increased the rate of return in 2001, and that most of the earnings resulting from trading occurred in the first two quarters of 2001. During this period, the trading operation was utilizing APS resources and contracts, and the personnel had been trained through working for APS. In fact, the entire APS marketing and trading operation was simply transferred to PWEC in 2001. There is no reason why the ratepayers who had supported those resources and paid for the training of personnel should not benefit from the trading operations.

Q. Regarding the writeoff, if it were appropriate to adjust actual earnings to determine what the Company would have earned without the writeoff, has the Company made the appropriate adjustments?

A. No. To consider what the rate of return might have been without the writeoff also requires increasing actual Company earnings for the foregone revenue. This presents a truer picture of where APS would have been if its rates had remained unchanged, since according to APS the "writeoff" and the rate reductions were intimately linked. If its rates had not changed, APS would have had additional revenues from 1999 through 2002 of $175.7 million (Response to LCA1-7). Thus, to demonstrate where APS would have been if its rates had not changed, after increasing expenses by the adjustment suggested by APS, the increase in amortization expense, we also must increase income. Exhibit LS-2 "undoes" the Settlement by adjusting the amortization expense, as the Company would do, and also increases revenues by the after-tax impact of the rate reduction. This computation again shows that APS would have overearned but for the rate reductions. The rates of return in 2000, 2001, and 2002 would have been 15.0%, 13.2%, and 10.8%. The major data responses that have been used in this computation and referred to elsewhere are contained in Exhibit LS-3.

Q. The Company has further claimed that it has been harmed because the Commission modified the order that approved the 1999 Settlement. Has the Company demonstrated that it has actually suffered significant financial harm because of this modification?

A. No. The response to LCA1-10 states that the Company made numerous concessions, including agreeing to less than $530 million in stranded costs, the writeoff, the rate decreases, the disallowance of 1/3 of divestiture costs, and the dismissal of litigation against the Commission. I will address each of these "concessions" below.

Q. Does the Company claim that it has suffered any other costs as a result of the change in Commission policy?

A. Yes. According to the response to LCA1-10, "It has also left part of the generation built to serve APS load effectively "stranded" at PWEC with the associated diseconomies and financial strain of having to maintain two separate organizations for the same essential utility function." (LCA 1-10)

Q. Has the Company established the value of what it has been denied by the cessation of the transfer of generating assets to PWEC?

A. No. There has been no demonstration of the actual cost of the diseconomies which are supposed to result from having two separate organizations. In fact, since PWCC basically transferred Mr. Bhatti and its generation planning functions from APS to PWEC, it is not evident that any costs have been duplicated. In response to LCA 19-458, the Company states that the cost of financing PWEC on a stand-alone basis was at least 264 basis points. However, PWEC's financing costs would have been higher than APS' financing costs even if APS generation assets had been transferred to PWEC, because PWEC is a competitive unregulated entity and thus is subject to more risk than the regulated utility.

Q. If there have been diseconomies resulting from the existence of the two separate organizations, need they persist into the future?

A. No. Any APS costs associated with generation will be included as part of APS' regulated revenue requirement. PWEC, a non-regulated entity, may or may not recover all of its costs through its competitive activities. PWEC may compete with other nonregulated generating entities that also presumably have higher financing costs than regulated entities.

Q. Could there have been circumstances in which PWCC would have had expectations of a more profitable PWEC?

A. The short-term profits of any competitive entity are affected by the vagaries of the market in which it operates. However, if PWEC purchased the APS generating assets at their fair market value, it would not have expected extraordinary profits over the long-run. PWCC would have expected PWEC to be very profitable if APS transferred its generating assets to PWEC at less than their market value. As noted below, APS testified in the Settlement proceeding that such was not its expectation.

Q. Please summarize your comments regarding the so-called "concessions" in the Settlement.

A. I have explained that the Company has not undercollected stranded costs, that the writeoff has no independent impact, that at least some of the rate reductions would have occurred even without the Settlement, and that APS cannot be certain that its rates would have remained unchanged at the conclusion of the stranded cost proceeding. The one-third of the divestiture cost does not comprise a substantial sum and by itself does not justify reversal of the wrute-off. (In Section VI I recommend allowing the Company to collect the one-third of the costs of divestiture.), Thus, I recommend that APS not be allowed recovery of the $234 million.

Q. Has the Company collected $350 million to cover the stranded costs agreed to in the Settlement?

A. It is on track to collect $353 million by the end of the period in which it was planning to collect stranded costs (July 2004). (DGR WP-33 p.54) Mr. Propper testified in Docket E-01345A-98-0473 as to how the recovery of Stranded Costs would be accounted for by the Company. The Company computed a Competitive Transition Charge, or CTC, designed to collect the $350 million from its customers. Actual annual sales to jurisdictional customers would be multiplied by the CTC, and also multiplied by the percentage of load eligible for Direct Access Service ("DAS") during each year. This methodology was consistent with how the Company computed stranded costs.

Q. Could you explain why the CTC was multiplied by total load eligible for DAS, rather than only by load that chose DAS?

A. Yes. Based on the concept of stranded costs, it is appropriate to multiply the CTC times the total load eligible for DAS because customers who continue to purchase generation from APS are contributing to the collection of APS' stranded costs. The standard offer generation price covers both stranded cost and the market cost of generation, so that customers who purchase generation from the Company are contributing to the collection of stranded costs through the standard offer price. Customers who choose Direct Access would contribute to stranded cost collection through an explicit CTC.

V. THE ISSUE OF STRANDED COSTS

Q. How are stranded costs defined?

A. The concept of stranded costs arose out of concerns that a company might be unable to collect all of the dollars that it had expended on generating assets if its customers were given the ability to purchase generation from other suppliers – in other words, if retail access were offered with no charge to customers for leaving. This would be a concern to a company when the embedded costs of the generating assets still to be recovered are greater than the revenues that the Company would receive by selling either the generating units themselves or by selling energy that becomes excess when customers choose alternative suppliers.

Another way of looking at stranded cost is as the difference between the value of the assets on the utility's books, or their net book value, and the market value of the same assets. This reflects the utility's position if it sells the assets. It might be interested in selling assets if it expected its generation load to decrease. If the market price is less than the net book value, the utility will not recover its full costs by selling the units, and would be considered to have stranded costs.

The Company seems to recognize this concept, as Mr. Wheeler testifies that "Stranded cost referred to the difference between the regulated cost of service for competitive electric assets, in this case generation, and what was then believed to be their market value." (Wheeler testimony, p.19) Stranded costs refer to the generation costs that the Company may be unable to collect when customers can choose other suppliers. Typically, a rate is developed which will allow the Company to collect these stranded costs from all customers.

Q. Has this definition and collection of stranded costs been used in other jurisdictions?

A. Yes. To my knowledge, all jurisdictions that have allowed utilities to collect stranded costs have computed stranded costs in a manner consistent with this definition: that is, comparing the market value of the assets with their book value. In some states, vertically integrated utilities have been required to sell their assets to the highest bidder. The sale price clearly establishes what the market is willing to pay for the assets, and the stranded costs which the utilities have been allowed to collect are the difference between the sale price and the book value.

Q. Does the $533 million figure that APS refers to as its stranded cost have any relevance to this case?

A. Only in that it is the basis for the claim that APS gave up something when it agreed to collect $350 million in stranded costs, rather than $533 million. APS attempted to demonstrate previously that it would have experienced $533 million of stranded costs if customers had chosen retail access. This figure was cited in the 1999 Settlement Agreement. APS' estimate was computed by multiplying the kwhs that were eligible for retail access (and thus might be lost to APS generation sales) by the difference between the Company's embedded generation costs and its projected market revenue, for six years, 1999 through 2004. However, this is too short a period to evaluate the value of the assets.

The Company's version of "stranded cost" represented generation revenues that APS would not have collected over the six year period if all customers who were allowed retail access chose alternative suppliers. This did not mean that if APS did not collect the $533 million it would be unable to recover its full investment in its generation. The $533 million computation only reflected sales and revenues from the generating assets over six years, rather than over the lives of the assets. The appropriate period should reflect the entire lives of the generating units which are being considered. This is because the units are producing economic value over their entire lives, not only over six years The short-run look at costs is similar to basing a claim that one has lost money on a house purchase by comparing the mortgage paid during six years to an alternative rental over the same period, and ignoring the fact that the house might be sold for more than the dollars remaining in the mortgage. In the case of generating plant, if, at the end of the six year period, the market value of the assets were greater than the book value of the assets at that time, the entity owning the units could recover the full market value of the assets by either selling generation at market prices or by selling the generating assets at their market value.

If the analysis were for a longer period of time, it is possible, and even likely, that the amount collected from sales into the competitive market would have been greater than the remaining embedded revenue requirement.

Q. Is there evidence in this case that illustrates the concept that a short-run view may appear to result in stranded costs, while a long-run view does not?

A. Yes. The Company states that ratebasing the PWEC units (i.e. pricing them at embedded costs) will cost customers more than paying market prices for energy in the near-term. It also claims that over the lives of the units customers will pay less in total net present value if they pay embedded costs rather than market prices. This illustrates the point that a short-run view does not capture the full value of such long-lived assets. The computation of the market value of the generating assets compared to the book values and the computation of the life-of-unit net revenue streams received from selling at competitive prices as compared to selling at embedded rates would accurately show the full value of the assets over their useful lives. This is because the market value of assets will typically be based on the net revenues that could be recovered from the assets over time. One method of estimating the value of the generating assets is to accumulate the estimated net revenues that the assets will receive from the competitive market, and to compute the net current value of that stream of net income. This is usually described as the Discounted Cash Flow method and should predict what the current market sales price of the units would be.

Q. Why does an accurate measurement of stranded cost require examining either asset sale prices or a rigorous analysis of generating units over their entire lives?

A. Although currently there may be a gap between embedded costs and market revenues, this gap will shrink and will probably reverse itself over time. As a result, in the later years of a unit's life, it is likely to be profitable in the market – that is, it will receive greater revenues by selling into the competitive market than it would have by selling at embedded costs.[2] This turnaround typically occurs because over time market prices tend to rise, while the embedded costs of a generating portfolio are likely to be stable or even to decrease, because the rate base tends to decrease as the initial investment is depreciated (i.e. costs are front-loaded). As a result, even if current embedded costs exceed market prices, lines depicting the two values over time usually cross in the future. Thus, typically

2 O&M costs will usually rise, which is the reason that embedded costs do not always decrease over time.

there are near-term years in which market revenues will be less than embedded cost revenues, and future years in which this relationship is reversed. The buyer of the asset will recognize the full value of the asset over time, so asset sales prices provide this correct valuation. [3] By focusing only on the next six years, APS' method for estimating stranded costs does not reflect the full value of the assets, and would overcompensate the Company for costs that are truly at risk of being stranded.

Q. Did the Settlement require APS to sell its generating assets for their market value?

A. No. In fact, the Settlement specified that the units should be transferred at then current book value to a competitive affiliate of APS.

A. What would be the result of this transfer at book value?

Q. It would mean that if the units at that time were worth less than book value, the competitive affiliate would lose money on the units. However, if the units were worth more than book value, the competitive affiliate (and therefore PWCC) would make profits from sales from these units.

Q. Was there other criticism of the Company's computation of stranded costs?

A. Yes. Staff criticized the Company's projection of market prices as being too low, based on information available at the time.

Q. Did the Company present any evidence prior to the Settlement regarding the market value of the generating assets at the time they would have been transferred to the competitive affiliate?

A. The Settlement proceeding did not contain any such analysis. However, Mr. Landon testified in the Settlement proceeding for the Company that the assets

[3] This is the reason that some jurisdictions have required divestiture before providing utilities with stranded costs; the sale of the units clearly represents what the market thinks the units are worth.

were being transferred at more than their market value, so the Company should not have anticipated that the APS assets would have created profits.

Q. What does the Company say currently about the market value of the APS assets?

A. The Company indicates that its estimate of the market value of the output of its (APS) units [redacted]

Q. Was the Company's method of computing stranded costs allowed by the ACC, and if so, why?

A. The Commission had provided for a methodology similar to that utilized by the Company, although neither the methodology nor the $350 million were discussed substantively in the Settlement order.

The decision in RE-0000C-94-0165 in Order 60977 allowed only two options for utilities to choose and to receive stranded cost recovery. These included either a divestiture of all generation assets, which would determine the amount of stranded costs, or the "Transition Revenues Methodology", which was intended to provide sufficient revenues to stay out of bankruptcy.

In Decision 61677, the Commission noted that this appeared to condition recovery of stranded costs upon forced divestiture, which it ruled was not in the public interest. The Commission at that time accordingly added another option for computing stranded cost. The additional option was labeled the "Net Revenues Lost Methodology". While this was described as a methodology similar to that set forth by APS, the Order did not provide detailed guidance as to the computation of stranded costs, and its discussion of the collection of stranded cost is different from that adopted in the Settlement. In the Settlement Order, the methodology issue was not discussed, and the $350 million that was to be collected was a result of negotiation.

Q. What bearing does the issue of stranded cost have on the current proceeding?

A. If the PWEC assets are rate-based, the Company may claim additional stranded costs associated with them. According to APS' methodology of calculating price differences for only a few years, there will be stranded costs associated with these units if APS' retail generation load decreases.[4] This is because typical cost of service treatment front-loads recovery of the cost of assets, so in the short-run even efficient units do not look profitable. However, if stranded costs were computed according to the discounted cash flow method, market sales from these particular units will probably be almost sufficient to recover embedded costs over the lives of the units. In fact, the major reason they might not be completely sufficient is that market prices at the present time appear to be below the long-run equilibrium.

VI. COMPETITION RULES COMPLIANCE CHARGE

Q. What is the Company requesting recovery of in the proposed CRCC?

A. The Company is requesting the approval of a Competition Rules Compliance Charge ("CRCC") which shall collect $49,334,000 plus interest over 5 years. This will result in an annual expense of $8,283,000.

Q. What costs are included in the $49 million?

A. According to Mr. Robinson, there are three parts: 1) costs associated with the implementation of Direct Access; 2) costs associated with divestiture; and 3) costs

[4] The existing rules would appear to prohibit stranded costs based on the PWEC assets, because of the date they were built.

associated with the implementation of Track B. These three categories of costs include the deferred balance as of December 31, 2002, plus costs the Company projects it will incur prior to July 1, 2004, plus the 1/3 of asset divestiture amounts that had not been included in the balance. Interest is included at the actual 2nd quarter 2003 interest rate. The total amount to be collected is reduced by the amount the Company projects will be overrecovered by December 31, 2004 through the CTC.

Q. What gave rise to these deferrals?

A. Provision 2.6 of the Settlement specified that "…the Commission shall, prior to December 31, 2002, approve an adjustment clause or clauses which will provide full and timely recovery beginning July 1, 2004, of the reasonable and prudent costs of... compliance with the Electric Competition Rules of Commission-ordered programs or directives related to the implementation of the Electric Competition Rules…"

Q. If the Commission previously approved the Settlement and the Settlement addendum that gave rise to these deferrals, what must be decided in this case?

A. I believe there are three issues. One is whether all of the costs being requested are collectible. This depends first, on whether the costs were all "reasonable and prudent" and second, on whether they were completely a result of the electric restructuring efforts. Another issue is whether the Company should be allowed recovery of the 1/3 of costs associated with divestiture which the Commission concluded should be borne by shareholders. The final issue is the period of time over which these costs should be recovered.

Q. Please describe the costs included in the Direct Access category.

A. Below I list the 13 categories listed by the Company. I also group related costs together into 6 categories for ease of discussion.

TABLE 1

CIS/Billing	Direct Access Capability
DA Coordination	
ESP Management	
WestConnect	FERC Compliance
Desert Star	
Financial	Direct Access Support
Generic Proceedings	
Inform & Educate	
Itron	Metering
Metering	
Scheduling	Load information
Settlement/Load Profiling	
(Overhead) Return Plus Benefit Loads	Overhead

Q. Were all of these costs required by Direct Access efforts, and required only because of Direct Access efforts?

A. It does not appear so. I believe that some of these costs would have been incurred without the efforts to develop Direct Access.

Q. Please describe the Direct Access Capability costs.

A. In order to comply with the Electric Competition Rule, the Company needed to enhance its customer data and its billing system. This would enable it to keep track of Direct Access, to bill different rates, and to communicate with potential alternative suppliers. According to the responses to RUCO 5.7 and to CNE/SE 1.8, this required additional personnel and mainframe capacity, which has resulted in deferred and ongoing lease payments for this capacity. There have also been additional payroll expenses which have been deferred.

Q. Are these unusual expenses or levels of expense?

A. In my experience, providing retail access generally requires additional Customer Information System and Billing ("CIS/Billing") activities. Bills usually need to be reformatted, additional customer data must be collected, and additional communication with customers and with retail suppliers must be provided for. These typically create additional costs. While the amounts spent by APS have been large, in my experience they are not dramatically out of line with such expenditures by other utilities that have unbundled rates and offered direct access. However, some of the dollars spent on CIS/billing probably provide the Company with additional capabilities that may have value in addition to providing customers with Direct Access. Some of the expenses that have been deferred in this category may have been necessary in the future in the absence of the Competition Rules.

Q. Do you recommend denial of some of these Direct Access Capability costs?

A. I have not seen information that would be a basis for denial of any of these costs. Amortizing these costs over a number of years is an appropriate way to respond to any costs that may provide additional services over a number of years.

Q. Please describe what you have categorized as the FERC Compliance costs.

A. In Order 2000 and Order 888, FERC has been requiring utilities to separate their transmission systems from their other operations in order to create truly open access to the nation's transmission system. The most recent manifestation of this effort is the establishment of Independent System Operators or Regional Transmission Organizations. Utilities in the Southwest have put efforts into forming complying organizations, first through Desert Star and more recently through West Connect.

Q. Do you recommend inclusion of these costs in the CRCC?

A. No. In response to CNE/SE 1.8 a, the Company states that these are the Company's share of development costs of first Desert Star and then West Connect, and notes that "Consistent with the Competition Rules, APS is supporting the development of an RTO." While these efforts would have contributed to a system that allowed Retail Access, I believe that the expenditures on West Connect and Desert Star would have been required whether or not Arizona wrote the Competition Rules and opened up Direct Access. The efforts to create a workable Independent System Operator ("ISO") or even a Regional Transmission Organization ("RTO") were necessary to respond to FERC's orders. These costs should not have been deferred for collection in the CRCC.

Q. What do you recommend with regards to costs in the Direct Access Support, Metering, and Load Information categories?

A. While these costs may have some value outside of Direct Access, it also appears that they were necessary to prepare for Direct Access. I recommend allowing these costs in the CRCC.

Q. What do you recommend with regard to Overhead costs?

A. The Settlement Order specified that all costs associated with Direct Access should be allowed. However, the "return plus benefit loads" costs included in the Company's requests must be reduced. Benefits associated with personnel whose salaries are included in the FERC Compliance category should be eliminated. From 1997 through 2002, the return component was based on the cost of short-term debt. (Response to LCA 25-533). Thereafter, it was computed on the basis of what the Company describes as the FERC-prescribed formula, which reflects equity as well as debt cost. I do not see a problem with this methodology.

Q. What are the issues associated with divestiture costs?

A. Again, they entail whether the costs were prudent, and whether they were all necessary for the efforts toward divestiture, and the issue of whether the utility should be denied 1/3 of these costs.

Q. What do the divestiture efforts consist of, given that APS did not divest?

A. The Company in response to LCA 25-543 describes the efforts as consisting of extensive analyses and preparation of submittals and filings that prepared for the transfer of plants. Further, they provided a breakdown of the almost $10 million of costs by category.

Q. Do you see any problems with the divestiture expenses?

A. It would be more accurate to say that I still have some questions regarding the level of expense. In particular, there are $2.5 million of internal Payroll-Related expenses, excluding inhouse legal expenses. These expenses suggest that the equivalent of between 7 and 11 full-time APS personnel worked on divestiture issues in 2000 and 2001. This strikes me as high, and may also have contributed to portfolio planning that had previously been performed by APS, but was being performed by PWEC during this period. There is additional discovery pending on this issue. I recommend that this expense be removed unless the Company response provides adequate support for this level of expense.

Q. What do you recommend with regard to the 1/3 of divestiture costs which the Commission concluded should be borne by shareholders?

A. I recommend that the Company be allowed to collect these costs. The Company expended these costs in response to an expectation of divestiture. These expenses were incurred solely in expectation of divestiture, and the Commission reversal of position on divestiture is therefore grounds to allow recovery of these expenses.

Q. What are the issues related to Track B costs?

A. It is not clear to me that these costs are allowed within the CRCC, as necessary to comply with the Electric Competition Rules. Purchasing power has always been a function of the utility, and will remain so as long as the utility has a responsibility to acquire power for any of its customers. The Track B costs were incurred out of the test year, and may have been higher than would be expected on an ongoing basis, but I do not recommend that they be collected in the CRCC.

Q. Have you computed a recommended number?

A. I have estimated the reduced annual CRCC based on these recommendations, that is excluding FERC compliance costs and the Payroll-related expenses in the Divestiture category. This results in an annual expense of $7.4 million, This computation is summarized in Exhibit LS -4.

VII. ALLOCATION ISSUES RELATIVE TO REVENUE REQUIREMENTS

Q. Please summarize the cost allocation issues that are directly relevant to the Staff computation of the total ACC revenue requirement.

A. The total revenue requirement supported by Staff is affected by the treatment of transmission costs that has been proposed by the Company and by the allocation of various costs between the retail and the wholesale jurisdiction.

Q. Please describe how transmission costs can be treated to develop transmission rates.

A. In a typical rate case, historic transmission costs are identified, and proforma adjustments may be made to reflect known and measurable changes. If the utility is “unbundling” its costs, it will allocate a portion of its administrative and general expenses to the transmission function, and will include in the revenue requirement calculation a return and income taxes on transmission rate base. This is the standard treatment of the cost of service in a retail proceeding.

Q. Have you been aware of any alternative approaches to setting transmission rates?

A. Yes. In states with retail access, the transmission rate may be based directly on the utility's Open Access Transmission Tariff (OATT).

Q. APS has made a number of adjustments to rate base and to expenses associated with the provision of transmission and ancillary services. Please describe them

A. APS has essentially removed the standard transmission costs from its revenue requirements and replaced them with transmission costs based on a different computation, that of the OATT expense associated with its load.

Q. Why has the Company proposed this different treatment?

A. FERC requires that utilities with unbundled rates bill Scheduling Coordinators under the provisions of their Open Access Transmission Tariffs. This should ensure that customers choosing alternative generation suppliers are charged for transmission service on the basis of the same FERC approved transmission rate as Standard Offer customers. The OATT contains rates for both transmission service and most ancillary services (excepting must-run service). The proposed revenue request reflects APS' OATT billings as expenses associated with transmission and ancillary services. If transmission rate base and allocated expenses were not removed from the cost of service used to determine rates, transmission related costs would be recovered twice. The capital costs of the portion of assets that support ancillary services have also been removed from rate base.

Q. What are the assets that support ancillary services?

A. For the most part they are generation assets that are run partly to provide such ancillary services as regulation and spinning reserves. The Company has estimated the amount of generation rate base that provides these services by analyzing which particular generating units have been used to provide these services, and removing the corresponding portion from rate base.

Q. How is the OATT expense which substitutes for the standard cost of transmission service computed?

A. The Company computes a proforma expense by applying the OATT tariff to its proformed billing determinants. This represents what its OATT bill would be for its proforma load, and is more consistent with the filed case than the actual test year OATT bill.

Q. **What is the dollar impact on customers if the proposed adjustment is accepted?**

A. This depends on the Commission's findings regarding various aspects of the proposed revenue request. If the Company's rate of return, depreciation expense, and any other adjustments that impact the transmission cost of service calculation are accepted, it appears that retail customers will pay approximately $14 million less under the Company's proposed approach than they would under the standard cost of service approach.

Q. Can you explain how this difference arises?

A. Not precisely. There are usually some differences between FERC rate filings and state retail filings, so that even if the Company filed a case at FERC to justify a new OATT at the same time that it made a state cost of service filing, the rates would not be identical. In particular, FERC typically approves a different return on equity, which is usually higher. This cost component alone suggests that retail customers might pay somewhat more under a FERC rate than under a retail cost computation, all else being equal. Other reasons for differences between FERC and retail rates may be that the treatment of some costs are different in the two jurisdictions, and the allocation between jurisdictions are different between FERC and the state commission. However, I expect that the biggest cause of the differences is that the OATT rates were based on costs and sales in test year 1995 (response to LCA 2.49). Since that time, I expect that rate base, expenses, and billing determinants have all increased, and the retail return requested in this proceeding is probably not equal to the return allowed in the existing OATT rate.

Q. What will the dollar impact on customers be if Staff's cost of service recommendations, rather than the Company's proposals, are adopted by the Commission and if the proposed transmission treatment is accepted?

A. It appears that the differences between the two approaches are much smaller, but it is likely that customers will still pay less under the proposal to replace transmission cost of service with OATT expenses.

Q. Will customers continue to pay less in the long run under the Company's proposal than they would have under the cost of service approach?

A. This depends on whether the Commission accepts a transmission cost adjustor. If it does, the amount that customers will pay will change. The amount is likely to change only slightly because of changed billing determinants, but may change by a significant amount if APS refiles its OATT and FERC approves a different OATT. Any resulting increase or decrease would flow through to customers through the transmission adjustor (called the TCCF). The Company should keep the Commission informed when it files new OATT tariffs at FERC.

Q. If the Company's proposed approach may not save customers much, is there any reason to accept it?

A. I believe that there is. Retail choice could be distorted if the transmission charges to standard offer customers are based on the cost of service calculation rather than on the OATT rates. As I understand FERC's policies and jurisdiction, any retail choice customer should be charged on the basis of the OATT. A customer that considers retail choice should make the decision based on the cost of generation from the utility versus the cost of generation from an alternative supplier. If the RA customer pays the OATT rate, and the Standard Offer customer pays the retail cost of service rate, the decision to choose retail access will be partly determined by the difference between the transmission rates, rather than on competitive generation prices.

Q. If the Commission accepts the treatment of transmission costs as proposed by the Company, does this require that it also approve the proposed transmission adjustor?

A. Accepting the proposed treatment of transmission costs does not require acceptance of the transmission cost adjustor. The adjustor was designed by the Company "to track changes occurring in a specific cost, whose base amount is included in retail rates." (Propper testimony, p. 18) The adjustor is necessary to ensure that Direct Access customers pay the same for transmission as Standard Offer customers, since Scheduling Coordinators will be charged the full OATT charge. Thus, if the OATT has changed since the OATT that was the basis for retail rates, and if there is not an adjustor, the DA transmission bill will be different from the Standard Offer transmission bill. I note, however, that even with the Company's proposal, there may be small differences between what customers pay due, for instance, to the timing of the imposition of the adjustor, and the fact that the adjustor will not be differentiated by class.

Q. The Company has proposed that specific details regarding a Transmission Cost Adjustor be developed subsequent to the acceptance of the TCA concept by the Commission. Is that an acceptable means of working out some of the implementation?

A. I believe that implementation details can be worked out subsequent to approval of the TCA.

Q. What are your recommendations with regard to the TCA?

A. I recommend that when the Company files a change in any of its OATT rates with FERC, it should also file a notice of such a filing with the ACC in this docket. In addition, it should be required to file its FERC application with the Utility Division director. The one change I would recommend to the Company's proposal is that the TCA should not take effect until the shortfall reflected in the Balancing Account reaches a trigger level that indicates a significant change. I suggest that a trigger of 5% of the total retail transmission cost approved in this case. When this trigger amount was reached, the Company should file for Commission approval of a TCA rate. I recommend that the Commission order the Company to file an implementation plant within 120 days of a decision in this case, for Commission approval.

Q. You also mentioned the allocation of costs between retail and wholesale. Are you making any recommendations that will have a significant impact on retail revenue requirements?

A. Yes. I recommend in section VIII that generation production capacity costs be allocated through use of the peak and average allocator, rather than the 4 Coincident Peak allocator which the Company has used. I believe that this better reflects cost causation, and is more consistent with ACC allocation precedents. This affects the allocation of some costs between retail and wholesale.

VIII. ALLOCATION AND UNBUNDLING OF COSTS

Q. Has the Company presented a cost of service study ("COSS") which unbundles its costs into different functions and allocates those costs between rate classes?

A. Yes, the Company has presented results of a fully unbundled and allocated cost of service study, sponsored by Mr. Propper. This type of study is an appropriate vehicle to produce the information necessary to develop unbundled rates based on embedded costs.

Q. Please describe the methodology used by the Company in its allocated Cost of Service Study.

A. Costs are "classified" as demand, energy, or customer related, and are also "unbundled" into various functions. Distribution costs, for instance, are categorized as substation, primary, and secondary. This subcategorization allows for a more accurate allocation of costs, since different customers place different demands on these parts of the distribution system. Costs which serve many functions, such as administrative and general costs, are spread among the functions. The functionalized costs are then allocated to the various rate classes. The study calculates the rates of return earned by each class based on the Company's depiction of its total costs, and also calculates total costs by function at the requested rate of return. These results can provide the basis for charging customers separately for different services, such as generation capacity, energy, transmission, distribution, and customer services.

Q. Has the Company proposed to base its unbundled rate components for each class on the results of its COSS?

A. No. As discussed by Ms. Andreassen, it has utilized the COSS only indirectly to affect its proposed rate design.

Q. Does the COSS identify directly the costs that the Company proposes to reflect in a Fuel and Purchased Power ("FPPAC") adjustor, so that it can be utilized directly to set a FPPAC?

A. No, it does not. Although there is a function called Production Energy, this includes more than fuel and purchased power costs. For instance, it includes operating and maintenance costs other than fuel and purchased power that are classified as energy related. This function also includes a share of administrative and general expense. Neither the other energy related costs nor the administrative and general expense would be tracked in a FPPAC.

Q. What did the Company's allocated Cost of Service Study indicate about the rates of return earned by the various rate classes?

A. The Company's COSS found that the ACC jurisdictional load was earning a considerably lower rate of return than the nonjurisdictional load. Within the ACC, all of the General Service classes except the Large General Service class earned more than the average Company test year rate of return. All other classes earned less than the average Company rate of return, with the streetlighting classes earning the lowest rates of return.

Q. Does the Company compute all functional costs in the same manner?

A. No. Transmission and ancillary service costs are measured in a different manner, as discussed in Section VII above. The cost of service study computes allocated transmission costs, but these costs are then removed and the OATT transmission expense is substituted to represent transmission costs.

Q. How does the Company model allocate costs between ACC jurisdictional load and the small amount of nonjurisdictional load?

A. Jurisdictional allocation is determined by the cost of service study using the same allocation basis that is used to allocate costs between rate classes. In other words, rather than a different allocator to identify the non jurisdictional portion of a cost, each functional cost line is allocated first to jurisdictions and then to classes using the same allocator. This treats nonjurisdictional customers consistently with how retail customers are treated, so that the FERC jurisdictional classes even receive an allocation of overhead costs.

Q. Do you support the methodology of using the same allocator for apportioning costs between jurisdictions and between rate classes?

A. Yes. If an allocator best reflects the reason that the Company incurred a particular cost, it should be used to allocate between jurisdictions as well as between classes.

Q. How has the Company allocated costs between classes?

A. Generation, distribution, and customer costs are allocated on the basis of different allocators which are supposed to reflect cost causation, or the basic reason that the costs are incurred.

Generation capacity costs, also referred to as production-related demand costs, are allocated on the basis of system peak load, as measured by the coincident peaks in the four summer months ("4CP"). Mr. Propper testifies that production related assets "are generally designed and built to enable the Company to meet its system peak load". (Propper, p. 5)

Q. Have you found that Mr. Propper has allocated costs appropriately?

A. For the most part I support the Company's choice of allocators. However, I believe that the allocation of generation capacity costs is incorrect. The allocation of generation capacity costs is important, because a very large proportion of the Company's total costs are categorized as generation capacity. Of the Company's requested total company revenue requirement of $1,944 million, $677 million is in the production capacity function. (AP WP-3 p.5)

Q. Why do you believe the Company's choice of allocator for generation capacity is incorrect?

A. The 4 CP allocation method for generation capacity does not reflect cost causation because it does not reflect how the utility makes decisions regarding generation investment. Using the 4CP method implies that all generation capacity costs can be explained by the utility's need to meet its peak load. While it is true that the amount of capacity in MWs that a utility will build (or purchase) is determined by its need to meet its peak load, the types of generation capacity that the utility acquires, and thus the dollars that it spends on capacity, are affected by a number of other considerations, but primarily by the tradeoff between capacity and energy costs. The cost of generating facilities per MW varies significantly between different types of generating units, from low capacity cost peaking units (roughly $400/KW) to very high capacity cost nuclear units (which cost more than $4000/KW). Normally, utilities build peaking units to meet peak needs. They build more expensive baseload plants when they expect to utilize them for many hours, so that they result in lower energy costs than if they had built peaking units. Mr. Bhatti agrees that "..the Company has sometimes built baseload plant [rather] than intermediate or peaking plant because the energy cost savings that result from building baseload plant rather than intermediate or peaking plant are greater than the additional capacity cost of the baseload plant". (Response to LCA 16-370) Customers with a high load factor, who use a large amount of energy relative to their peak loads, benefit from baseload plants because energy costs are lower than they would be without these plants. If capacity costs are allocated only on peak load, the proportion of capacity costs that high load factor customers pay for will not reflect the impact of the capacity dollars spent to reduce their energy costs. The high load factor customers pay less for energy, but do not pay their fair share of capacity costs that gave rise to the low energy costs. Conversely, allocation on the basis of peak alone results in low load factor customers, such as residential and small general service customers, paying a high proportion of generating capacity costs even though they do not receive a high proportion of energy savings.

Q. How do you recommend allocating generation capacity costs?

A. There are a number of allocation methods that reflect the fact that much of generation capacity cost is incurred in order to reduce energy costs and benefit high load factor customers. In this case I recommend the "peak and average" method, which allocates a portion of generation capacity costs based on peak use and the remaining amount on energy. This method is relatively simple, requires less data than more sophisticated methods, and reflects the basics of cost causation better than allocating on peak alone.

Q. Have you estimated the cost of serving each class consistent with Staff recommendations on revenue requirements and with your recommendations on the allocation of generation capacity costs?

A. Yes. The Company provided me with the proprietary models that it uses to develop expense and ratebase inputs, and with the model that allocates these costs, and also assisted me in the use of these models. (Supplemental response to LCA 2-26) I have modified the inputs to these models to estimate class unbundled revenue requirements based on Staff's recommendations regarding revenue requirements and allocation.

Q. Please describe how you modified the cost of service model to reflect Staff's adjustments to revenue requirements.

A. First, I changed the demand production allocator from the 4 CP allocator to a Peak and Average allocator. Next, the total Company costs were modified.

The Company's model allocates what the Company depicts as test year costs and also all of its proforma adjustments. For the major Staff adjustments made to eliminate ratebasing of the PWEC assets and the reversal of the writeoff, it was possible to utilize the Company's models directly. The results of this process I will refer to as the "adjusted model." All of the proposed proforma adjustments are represented in the model by discreet "switches"; by turning off the switch, the model removes all costs associated with the adjustment. I rejected the rate base and expense adjustments associated with ratebasing the PWEC units and with reversing the writeoff. The model reduces the cost of service by the dollars reflected in these two adjustments.

Q. Did reversing these proforma Company adjustments require anything other than reversing the steps the Company took to make these adjustments?

A. Yes, in one instance. The Company proposes that the rate of return should be higher if the PWEC assets are not ratebased. The COSS model reflects this rate of return through a revenue component of the PWEC adjustment. That is, the cost of service model computes costs associated with an 8.6% ROR. The Company would reflect the reduction in return that would result from utilizing the total Company ROR of 8.3% in the allocated cost model by entering a revenue increase associated with ratebasing the PWEC units. Since Staff does not agree that it is appropriate to utilize a different capital structure and a higher ROR if PWEC is not ratebased, when I "turned off" the PWEC adjustment I did not make a revenue adjustment for a different rate of return. I did enter a reduction in revenues associated with off-system sales that would not be made without the PWEC units.

Q. Did you also estimate the impact of the other adjustments recommended by Staff that were not simply a matter of reversing the Company's proforma adjustment?

A. Yes. Staff is supporting a lower return on rate base than the Company has proposed. We have modified the Company's model to reflect this lower return.

The adjustments proposed by Mr. Dittmer and Mr. Majoros are somewhat more complicated because they reflect changes to various items of rate base and expense that are either changes to test year amounts or are partial changes to the Company proforma adjustments**.** In order to reflect the impact of these adjustments on class revenue requirements, I made discreet "below the line" changes to the model-produced revenue requirements.

Q. How did you allocate these adjustments between functions?

A. This was a two step process. Rate base and expense adjustments were reconciled to Staff's case, and then were allocated across functions. Staff's additional jurisdictional rate base adjustments were either functionalized as production capacity (deferred Pacificorp gain), distribution (eliminate capital vehicle lease), or as miscellaneous rate base. The miscellaneous rate base adjustment reflected the remaining difference between the adjusted model rate base, the specific production capacity and distribution capacity adjustments, and the final Staff ACC rate base. These rate base adjustments were then allocated to the ACC functional revenue requirements on the basis of the direct functionalization produced by the adjusted model. For example, the additional proforma distribution rate base adjustment was allocated among the distribution and customer accounts functions by the same percentage that total rate base in these functions was spread by the adjusted model. The miscellaneous rate base adjustment was spread across all functions that contained rate base costs. Expenses were treated similarly, with the fuel and purchased power adjustment functionalized as production energy and all remaining adjustments allocated as expenses excluding energy expense.

Q. Please describe the estimation of class unbundled revenue requirements.

A. Again, the adjusted model did most of the work. The additional proforma functionalized adjustments were allocated to classes based on the allocation of each function by the adjusted model to the class. For instance, if the adjusted model allocated x% of distribution substation plant to the Small General Service class, I would also allocate x% of the total proforma adjustment that was functionalized as distribution substation plant. The adjusted class rate base by function was added to the model rate base, and the return and associated income taxes were computed. The adjusted class expenses were added to the adjusted model's expenses by function, and totaled to produce the revenue requirement for the class and the function. The adjusted revenue requirement results for the ACC jurisdiction class are presented in Exhibit LS-5.

Q. Will your results be identical to those that would be derived from making each expense and rate base adjustment within the model?

A. No, but the results will be close enough to judge what the percentage impacts on customer classes would be of setting revenue requirements at the cost of service. At the conclusion of the case, the Company should file a revised allocated cost of service study that reflects more exactly all adjustments approved by the Commission.

Q. What are the impacts on class rates of return of changing the generation capacity allocator alone, while not changing the requested revenue requirement?

A. The total Company return does not change, of course, nor does the general relationship between major retail class rates of return, that is, the residential rate of return is lower than the general service class as a whole. However, the differentials between the class rates of return are generally reduced. The streetlighting classes' deficiencies increase significantly as the production demand allocator is changed to peak and average.

Q. Please describe the results of the revised allocation of the Company's revenue requirement.

First, the nonjurisdictional ROR decreased to a negative return. The overall residential class ROR became positive, and the General Service ROR, while still positive, decreased. The cost of service study showed that for each class to earn the allowed rate of return, only the irrigation, streetlighting, and Large General service, and the Residential E-10 would need rate increases. Rates to other classes need to be decreased to result in equal class rates of return. Exhibit LS-6 shows the computation of class earned rates of return based on Staff revenue requirements.

IX. CONCLUSIONS

Q. Do you agree that the Company is entitled to recovery of the $234 million?

A. No. The request clearly does not meet standard ratemaking criteria. On a going-forward basis, there is no evidence that this reduction has any significant impact on rates that the Company is filing in this proceeding.

This issue is not about stranded cost, but about rate reductions which the Company agreed to 4 years ago as part of the Settlement. It is true that Commission policy has changed, and the movement toward divestiture that was envisioned 4 years ago has not occurred. However, to allow the Company now to increase rates to recover some of the rate reductions agreed to in 1999 is simply retroactive ratemaking. The Company cannot demonstrate that rates would not have been reduced in the absence of the Settlement. It has also not demonstrated that it has suffered significant financial harm as a result of not being able to divest its generating assets to PWEC. I do not think the Company has provided justification as to why the Commission should take the highly unusual step of increasing the Company's rates to replace revenue which the Company did not earn in previous years, particularly since such additional revenues would have created additional overearning in some of those years.

Q. What are your recommendations regarding the transmission cost adjustment and the CRCC?

A. I recommend that the Commission accept the proposed treatment of transmission and a transmission cost adjustment mechanism. Further, I recommend that the Commission approve a CRCC which will recover the requested Direct Access costs, (excluding what I have categorized as FERC-compliance costs, and associated benefits), and Track B costs. With regard to divestiture costs, I recommend that the Company be allowed to collect 100% of these costs excluding the Payroll-Related costs.

Q. What are your recommendations with regard to the allocated cost of service study?

A. I recommend that production capacity costs be allocated on the basis of the peak and average allocator. The functional revenue requirements that I have estimated reflect the results of Staff's revenue requirement recommendations. Further, final functionalized costs should be determined on the basis of the final adjustments accepted by the Commission.

Q. Does this conclude your testimony?

A. Yes, it does.